FORWARD SEISMIC MODELING: THE KEY TO UNDERSTANDING REFLECTION SEISMIC AND GROUND PENETRATING RADAR (GPR) TECHNIQUES

Neil Anderson (nanders@umr.edu) and Steve Cardimona (cardi@umr.edu)

Department of Geology and Geophysics, University of Missouri-Rolla, Rolla, MO

Abstract

Forward modeling of reflection seismic data is a computational process through which a geologic model (units: horizontal distance, vertical depth; layer acoustic impedance) of the subsurface is transformed into a synthetic reflection seismic record (units: horizontal distance, 2-way travel time; reflection amplitude). Synthetic seismic records (synthetics) are often generated both before and after the acquisition of reflection seismic field data.

Synthetic seismic records generated before field acquisition are typically used to determine if an intended/expected geologic target will generate an interpretable signature on output processed reflection seismic data. Pre-acquisition synthetic records also aid in selection of appropriate field acquisition parameters. Synthetic records generated after acquisition and processing of seismic field data are used to identify specific reflections (events) observed on field seismic data and to constrain conceptual geologic interpretations. Post-acquisition synthetic seismic records facilitate the interpretation of the processed reflection data, particularly if the corresponding geologic models were generated from “ground-truth” (borehole sonic and density logs).

Forward modeling of ground penetrating radar (GPR) data is in many ways analogous to the forward modeling of reflection seismic data. The main practical differences are related to the nature and scale of the geologic (or otherwise) models employed. GPR geologic models depict spatial variations in dielectric constant and conductivity as opposed to acoustic impedance. Units incorporated into GPR geologic models can be as thin as one millimeter (or less), whereas lithologic units incorporated into reflection seismic geologic models seldom have thicknesses of less than one meter.

Introduction

Forward modeling of geophysical reflection data is a tool used as a survey design aid and to constrain the interpretation of recorded/processed reflection seismic and ground penetrating radar (GPR) data (Figure 1). Although most of the concepts to follow can be applied to both reflection seismic and radar data, this paper will focus on reflection seismic data considerations and examples. A section on GPR is included to highlight important differences between the two reflection data types.

Forward seismic modeling is the process through which a subsurface geologic (acoustic impedance) model, in one- two- or three-dimensions, is transformed into a synthetic seismic record (record) of one-, two- or three-dimensions (Figures 2 and 3). Vertical depths within the geologic model are converted to two-way transit time. Acoustic impedance (product of velocity and density) contrasts within the geologic model are converted to reflection amplitudes (Figures 2 and 3). Often, the relationships between geologic models and corresponding synthetic seismic records can be readily deduced through visual examination.

Synthetic seismic records are typically generated both before and after the acquisition of seismic field data. Synthetic seismic records generated before field acquisition are used to determine if an intended/expected geologic target will generate an interpretable signature on output processed reflection seismic data. Synthetics can also be a valuable tool with respect to the design of an acquisition program (re: field acquisition parameters, sources, receivers, fold, etc.). Synthetic records generated after acquisition and processing of seismic field data facilitate the interpretation of the processed field data, particularly if the corresponding geologic models were generated from “ground-truth” (proximal borehole sonic and density logs). Synthetics make the confident correlation of the observed reflections and geologic interfaces possible, and verify that the seismic responses of interpreted conceptual geologic models are consistent with the actual seismic data. They are essential interpretation tools.

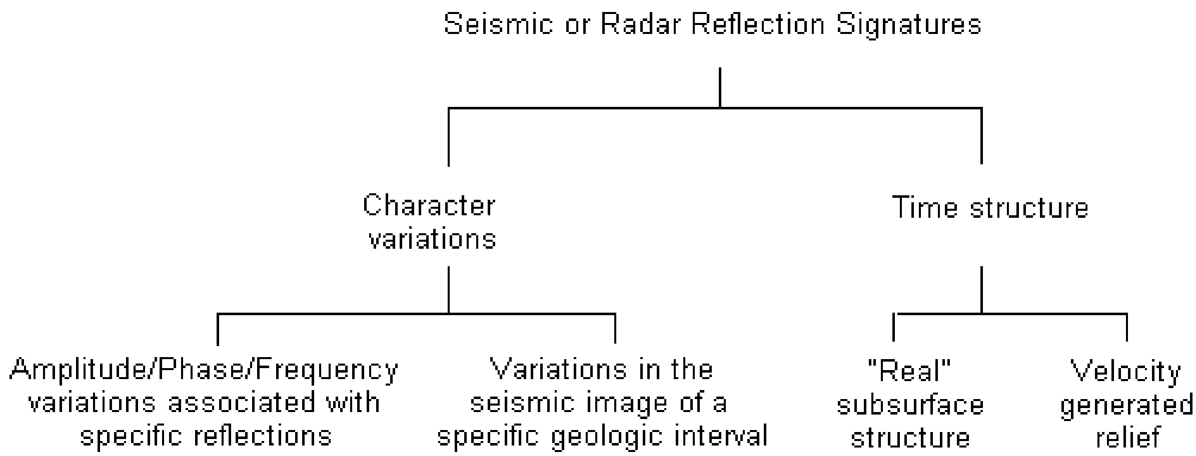


Figure 1. *The reflection seismic (or GPR) signature of a geological body (or otherwise) can be categorized in terms of character variations and time-structure.*

Correlation between Geologic Models
and Synthetic Seismic Sections

The relationship between geologic models and corresponding synthetic seismic records is relatively straight forward, particularly if the synthetic records have vertical incidence - thereby simulating migrated reflection seismic profiles. Figure 3 depicts a 2-D geologic model and corresponding normal and reverse polarity 2-D, vertical incidence, synthetic seismic sections - generated using a 60 Hz zero-phase Ricker wavelet. Examination of the geologic model (caption A) and the normal polarity synthetic record (caption B) illustrates the direct relationship between the spatial location of geologic horizon **1/2** and the spatial location of reflected event **1/2**. More specifically, at any trace location, the arrival time of event **1/2** (denoted by apex of wavelet peak) can be calculated using the following general equation:

$$\mathbf{T_N = 2Z_N/V_{NAV}} \qquad \text{equation 1}$$

where $\mathbf{T_N}$ is the arrival time of the **1/2** event (two-way travel time at specified trace location), $\mathbf{Z_N}$ is the vertical depth from datum to horizon **1/2** at the specified trace location, and $\mathbf{V_{NAV}}$ is the average velocity from datum to event **1/2** at the specified trace location. The magnitude ($\mathbf{R_n}$) of event **1/2** (relative to the normalized amplitude of the Ricker wavelet) is calculated using the following general equation:

$$\mathbf{R_n = (V_{n+1}\rho_{n+1} - V_n\rho_n)/(V_{n+1}\rho_{n+1} + V_n\rho_n)} \qquad \text{equation 2}$$

where $\mathbf{R_N}$ is the reflection coefficient (and relative magnitude of the wavelet) of **1/2** interface, $\mathbf{V_n}$ is the average velocity of the 1st layer, and ρ_n is the density of the 1st layer. Essentially, horizon **1/2** has been replaced in time by a suite of closely spaced wavelets with arrival time ($\mathbf{T_N}$) and relative magnitude ($\mathbf{R_n}$).

The relationship between horizon depth and arrival time is slightly more complex when dealing with 2-D or 3-D diffraction synthetic seismic records. In these cases, the synthetic records simulate non-migrated seismic data and travel times are calculated either along ray paths normal to the reflecting interface or along diffraction ray paths. The result is that synthetic events originating from dipping surfaces and discontinuities on the geologic model are not placed in their correct spatial location of origin on the output synthetic seismic profile.

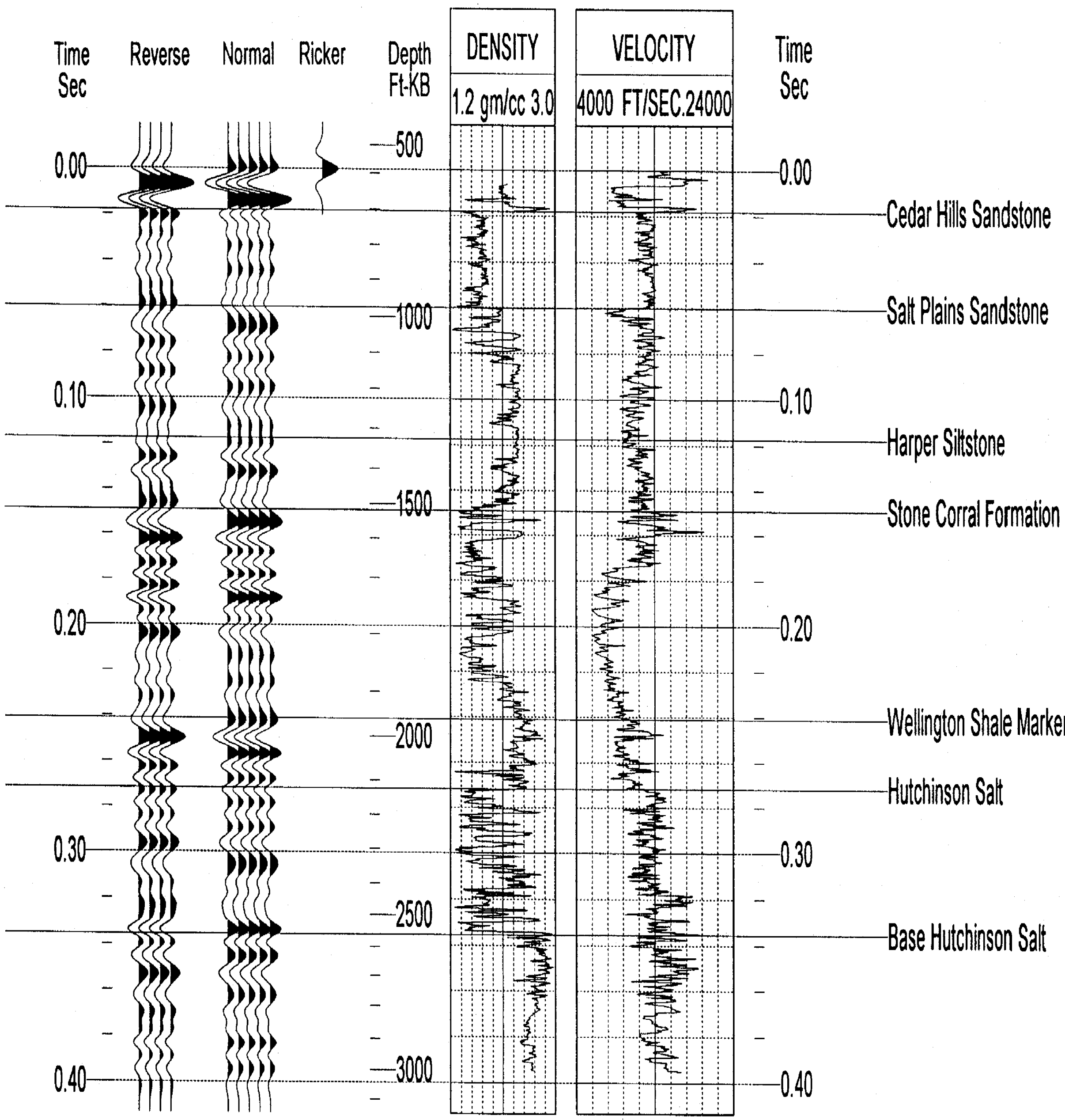


Figure 2. *Example digital velocity and density log time series (1 ms sampling interval), and corresponding normal and reverse polarity synthetic seismograms (1-D reflection seismic sections, each comprised of multiple identical traces). The synthetic seismic traces were generated by convolving the digital reflection coefficient time series (function of acoustic impedance contrast at each digital interface) with a 60 Hz zero-phase Ricker wavelet. Positive acoustic impedance contrasts (increase in product of velocity and density with depth) correspond to "peaks" (deflections to the right) on normal polarity traces; negative acoustic impedance contrasts correspond to prominent "troughs". The "arrival time" (two-way travel time; see Equation 1) of a zero-phase wavelet is measured at its apex. In the example, the Wellington Shale Marker is characterized by a positive acoustic impedance contrast and represented by a prominent peak (two-way transit-time of 0.241s) on the normal-polarity synthetic seismogram. (Note: Depth scale is non-linear.)*

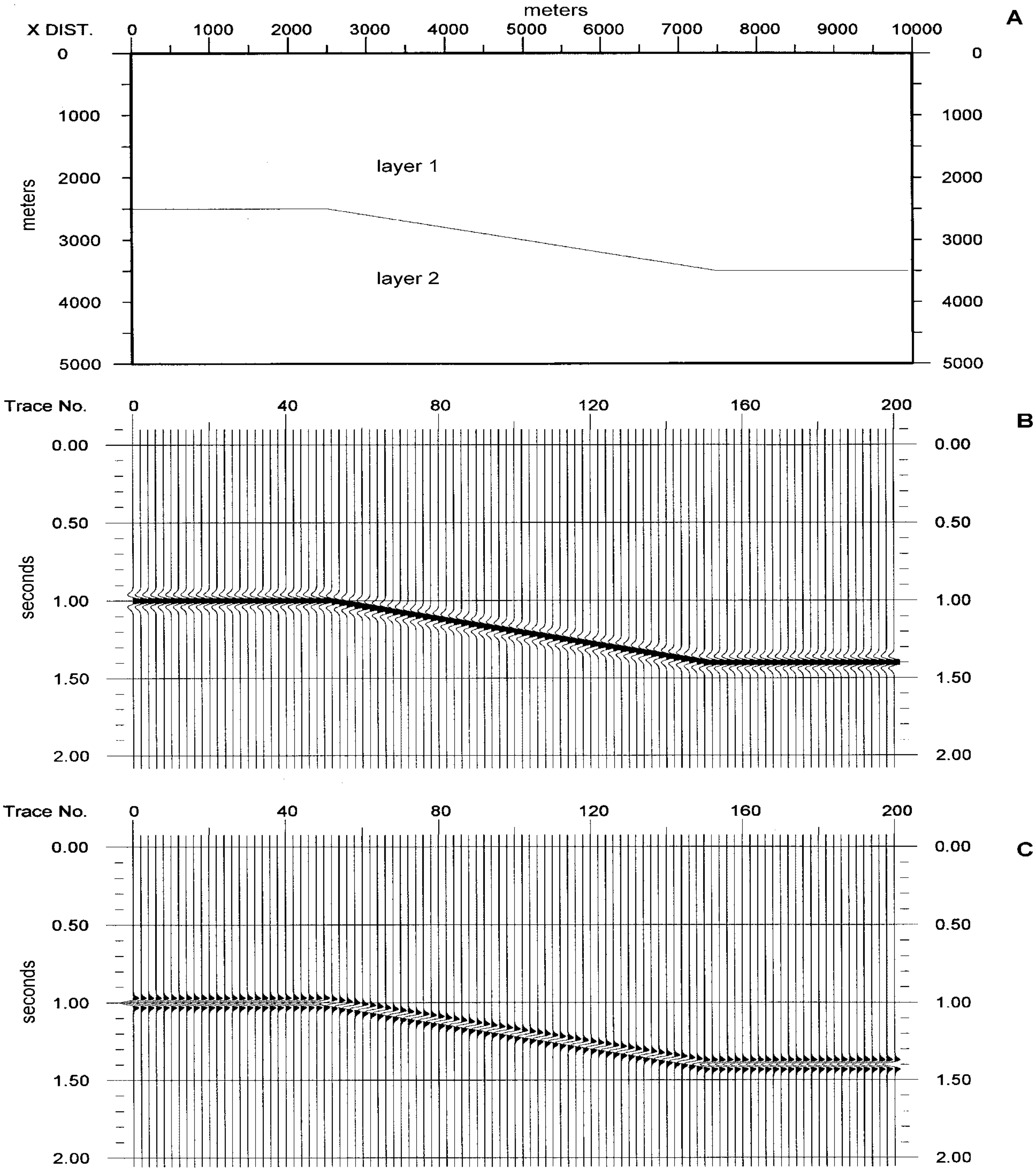


Figure 3. *Real structural relief in the subsurface is manifested as time-structural relief on reflection seismic data. Figure 3A is a depth section (geologic model). Layer 1 has a velocity of 5000 m/s and a density of 2400kg/m^3; Layer 2 has a velocity of 5000 m/s and a density of 2800kg/m^3; horizon 1/2 therefor has a positive acoustic impedance. Figure 3B is a vertical incidence, normal polarity synthetic seismic section generated using a 60 Hz zero-phase Ricker wavelet. At any trace location, the apex of the peak represents the two-way travel time of reflected event 1/2. (Note: A vertical incidence synthetic seismic section is analogous to a migrated seismic profile in that all seismic reflections are in their correct spatial location of origin.) Figure 3C is a reverse polarity synthetic seismic section generated using the same geologic model and synthetic wavelet.*

The 1-D synthetic record (seismogram) of Figure 2 also simulates migrated seismic data, in that the reflected events are placed in their proper spatial location of origin (in terms of arrival time), and reflection amplitudes are calculated on the basis of velocity/density contrast. The main difference between Figures 2 and 3 (other than number of dimensions) is that the 1-D geologic model is comprised of multiple layers each with a time-thickness of 1 ms. As a result of the close spacing of these layers, the reflections associated with adjacent horizon interfere. In places, interference is constructive; elsewhere interference it is destructive.

Reflection Signatures

The reflection seismic signature of a subsurface body includes all features in recorded reflection seismic data that can be confidently attributed to the presence of that body. Geophysical signatures in reflection seismic sections have two basic components: time-structural relief and character variations (Figure 1). The seismic signature of a subsurface body is usually best defined through forward modeling.

The time-structure component

The time-structure component of the seismic signature of a geological interface represents lateral variations in the vertical positioning of a reflection (event) across a seismic profile. These variations are due to “real” subsurface structure (Figure 3) and/or velocity-generated, time-structural relief (Figure 6) or both (Figure 7). “Real” subsurface structure can be the result of primary depositional patterns, post-depositional deformation (faulting, folding, uplift, diapirism), erosion, salt dissolution, differential compaction, etc. Velocity-generated time-structural relief is due to lateral variations in the average velocity of the sedimentary section overlying the reflector of interest, and can be caused by lateral facies variations and lateral variation in the thickness of individual sedimentary layers (Figure 7).

When seismic modeling is done prior to the acquisition of field data, the interpreter is generally attempting to determine whether the time-structural relief component of the seismic signature of the geological objective will be interpretable on processed field seismic data. In many instances, the corresponding adjustment of field acquisition parameters can ensure the geologic target is effectively imaged. When modeling is done after the acquisition of the data, the interpreter is generally trying to determine the nature of the geological feature that generated the time-structural relief observed on processed seismic sections.

Another use of modeling is to demonstrate how a component of time-structural relief on field seismic data can result from inappropriate data reduction and analysis techniques. Incorrect static corrections or too little care in choosing appropriate processing parameters can introduce artificial time-structural relief (Figures 8 and 9). The interpretation caveat is that the processing history should always be included with any seismic section that is handed over to the interpreter.

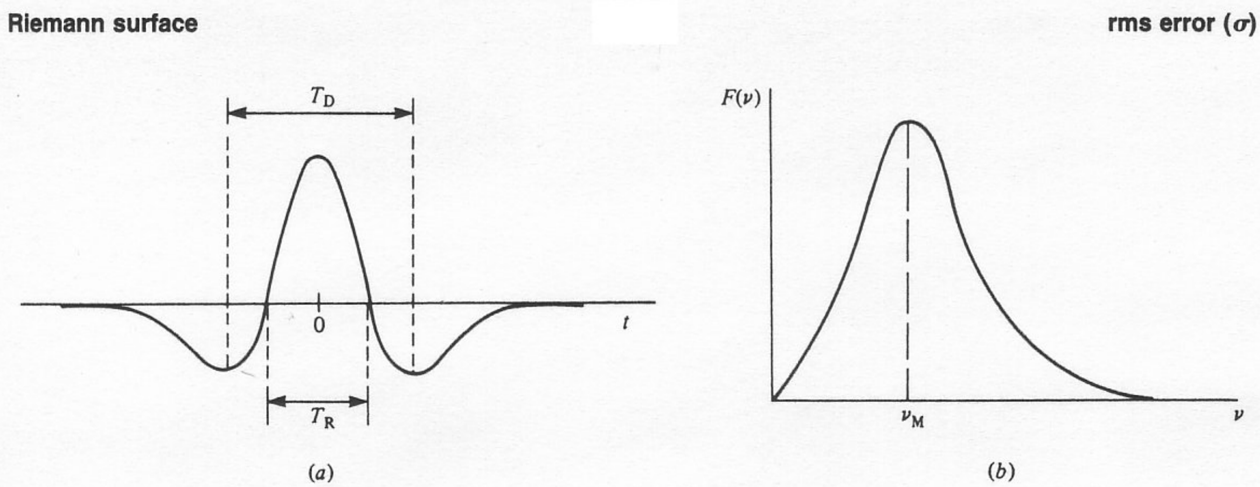
Character variation component

Character variations can be classified as lateral changes in amplitude and/or phase along a specific seismic event, or as lateral changes in the seismic image of a specified unit. Amplitude and/or phase variations typically occur as a result of constructive and destructive interference (Figures 10 and 11), lateral variation in acoustic impedance contrast (Figure 12), focusing and defocusing (Figure 13), diffractions (Figure 14) and differential attenuation. Lateral variations in the seismic image of a specified unit typically result from facies variation within that unit (e.g. reef to off-reef transition as in Figure 14). Character variations that are independent of the body of interest are not considered to be components of the seismic signature of that body. This includes interference from noise and some multiple-reflected arrivals (Figures 14 and 15).

When forward modeling is done prior to data acquisition, the interpreter is attempting to determine whether the character variation component of the seismic signature of the geological objective will be seismically visible. When modeling after data acquisition, generally an attempt is being made to deduce the geological origin of an observed seismic amplitude or phase anomaly.

Selection of an Appropriate Wavelet

The 1-D synthetic seismic record depicted as Figure 2 was generated using a 60 Hz, zero-phase, Ricker wavelet. The 2-D synthetic seismic records depicted as captions B and C in Figure 3 were generated using normal and reverse polarity, zero-phase, 60 Hz Ricker wavelets, respectively. A zero-phase, Ricker wavelet, as defined by Sheriff (1994), is can be specified by a single parameter Gaussian function and third derivative of the error function (Figure 4).



$$f(t) = (1 - 2\pi^2\nu_M^2 t^2)e^{-\pi^2\nu_M^2 t^2} \leftrightarrow \left(\frac{2}{\sqrt{\pi}}\right)\left(\frac{\nu^2}{\nu_M^3}\right)e^{-\nu^2/\nu_M^2} = F(\nu).$$

Also,

$$T_0 = \sqrt{6}/\pi\nu_M \text{ and } T_R = T_0/\sqrt{3}.$$

The mean frequency $\nu_{mean} = (2/\pi^{1/2})\nu_M$ and the median frequency $\nu_{median} \approx 1.08\ \nu_M$.

Figure 4. *Ricker wavelet. (a) Time-domain and (b) Frequency-domain representations (after Sheriff, 1994).*

Ricker wavelets are often used to generate synthetic seismic records (Figure 5). To ensure a reasonable match, the frequency of the synthetic Ricker wavelet used is generally estimated on the basis of a qualitative and/or quantitative analysis of acquired field reflection seismic data. If the field seismic data have been processed and transformed into zero-phase equivalent, a zero-phase synthetic Ricker wavelet is often used. If the field seismic data were acquired using an impulsive source - but have not been transformed into zero-phase equivalent during processing, a minimum-phase synthetic Ricker wavelet is often used. The polarity of the synthetic wavelet employed is a function of the polarity of the interpreted field seismic data. (Some interpreters prefer to work with normal polarity reflection seismic data; others prefer to work with reverse polarity data; Figure 5.)

The effects of a lateral change in the acoustic impedance of a continuous interface are illustrated by the normal polarity synthetic record displayed in Figure 12. On synthetic record of Figure 12B, the reflected event originating from the 1/2 interface gradually changes from a high-amplitude peak (extreme left) to a high-amplitude trough (extreme right) as a result of a corresponding change in acoustic impedance contrast. The accurate modeling and understanding of such character variations is often "key" to correctly interpreting processed reflection seismic data.

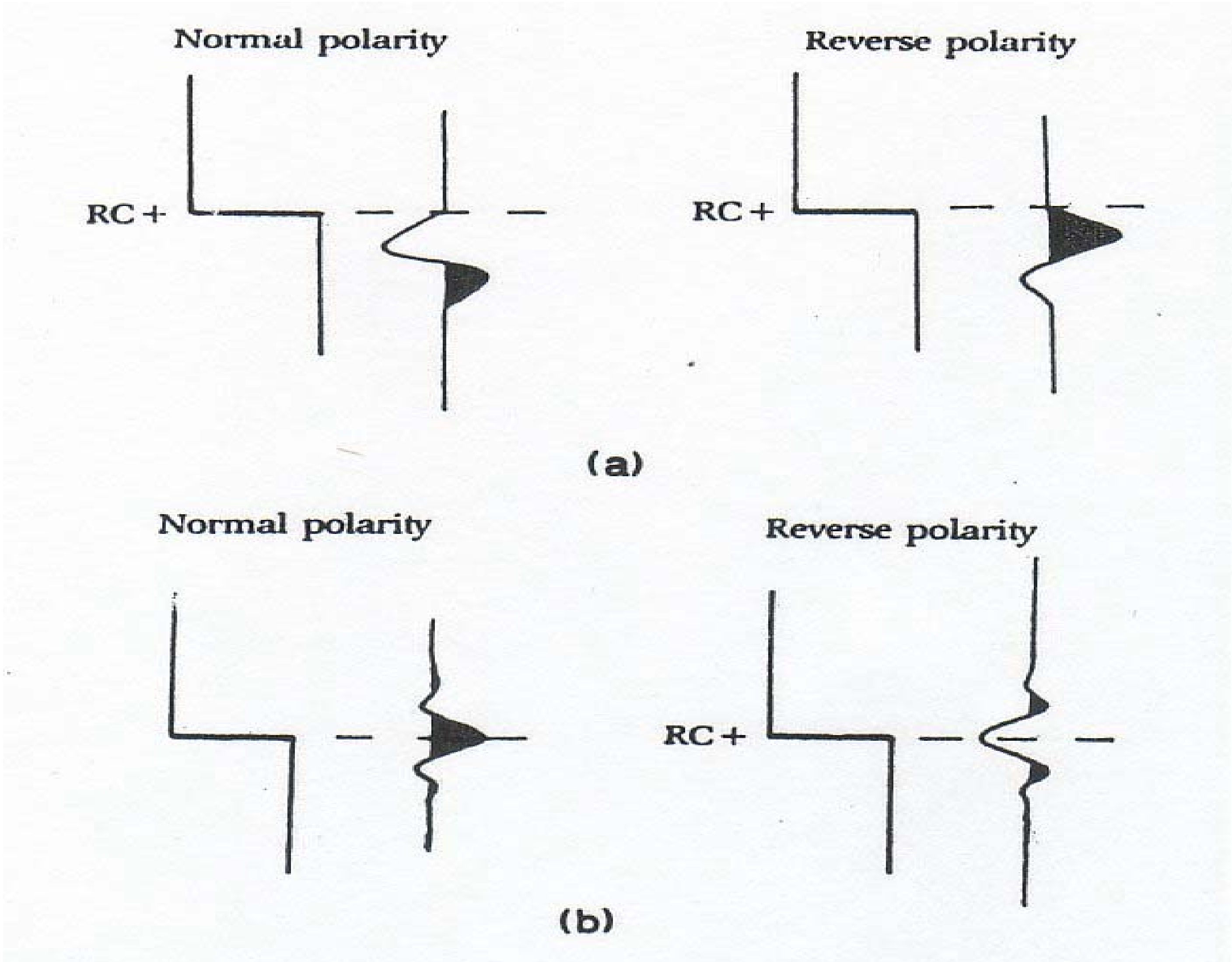


Figure 5: *Polarity conventions. For a positive reflection (increase in acoustic impedance), a minimum-phase wavelet (5a) begins with a downkick, and (5b) the center of a zero-phase wavelet is a peak. (After Sheriff, 1995.)*

In some instances, the recorded wavelet on interpreted data cannot be accurately modeled using a minimum-phase or zero-phase Ricker wavelet. In such circumstances, models may be generated using a phase-rotated synthetic Ricker wavelet or any one of a number of other standard wavelets (Ormsby, Burtterworth, etc.; Sheriff, 1994). Alternatively, a suitable synthetic wavelet can often be extracted directly from the processed field seismic data (through an analysis of the phase and amplitude spectrum or by digitizing an isolated wavelet). In some instances, the interpreter may determine on the basis of visual examination or spectral analyses of field seismic data that the shape of the recorded seismic wavelet changes as a function of travel time (due to attenuation). In such instances, a time-variant synthetic wavelet may be employed.

In certain situations, useful synthetic seismic records can be generated even if the synthetic and recorded wavelets are not near-exact matches. For example, the magnitude of time-structural relief and the polarity of the 1/2 interface (Figure 3) could also be accurately estimated on a synthetic record generated using a minimum-phase 40 Hz Ricker wavelet. In contrast, subtle interference patterns and phase variations observed on processed field seismic data are best interpreted with the aid of near exact synthetic wavelets. Interference patterns and phase variations are observed on Figures 5, 10, 11 and 12.

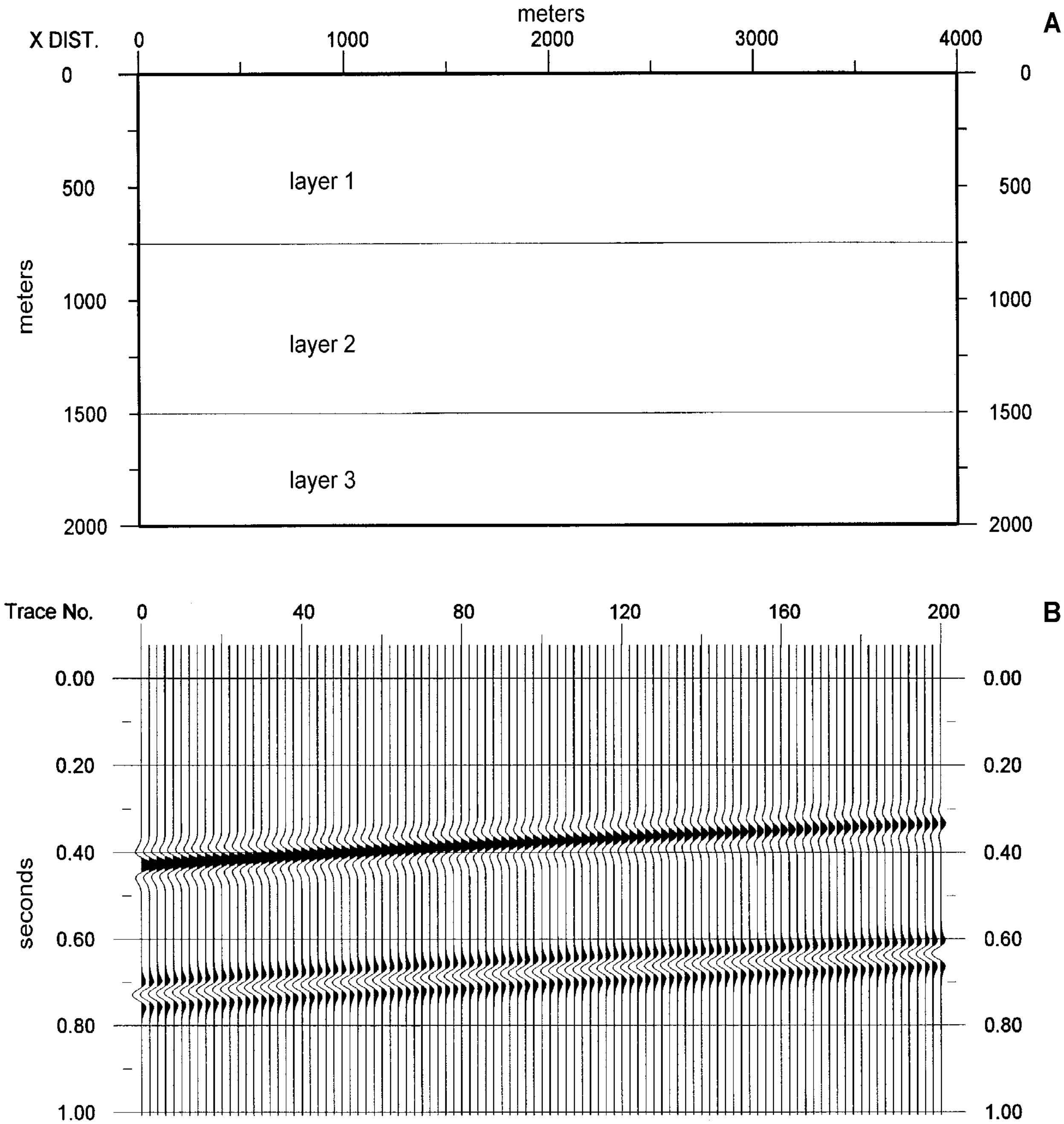


Figure 6. *Lateral variations in the acoustic velocity of the subsurface generate time structural relief. Figure 6A is a depth section (geologic model). Velocity of Layer 1 varies laterally from 3500 m/s (extreme left) to 4500 m/s (extreme right); Layer 2 has a velocity of 5000 m/s; Layer 3 has a velocity of 4000 m/s; densities are constant. Horizon 1/2 therefor has a variable acoustic impedance. Figure 6B is a vertical incidence, normal polarity, synthetic seismic section generated using a 60 Hz zero-phase Ricker wavelet. At any trace location, the apex of the peak represents the two-way travel time of reflected event 1/2. The apex of the trough represents the two-way travel time of reflected event 2/3. In a relative sense, event 1/2 is "pulled up" on the right-hand side of the synthetic seismic section. Alternatively, this event is "pushed down" on the left-hand side of the synthetic section. (Note: Even though the synthetic seismic events dip from right to left, the wavelets are in their proper spatial locations of origin. Hence this synthetic is analogous to a migrated seismic profile.)*

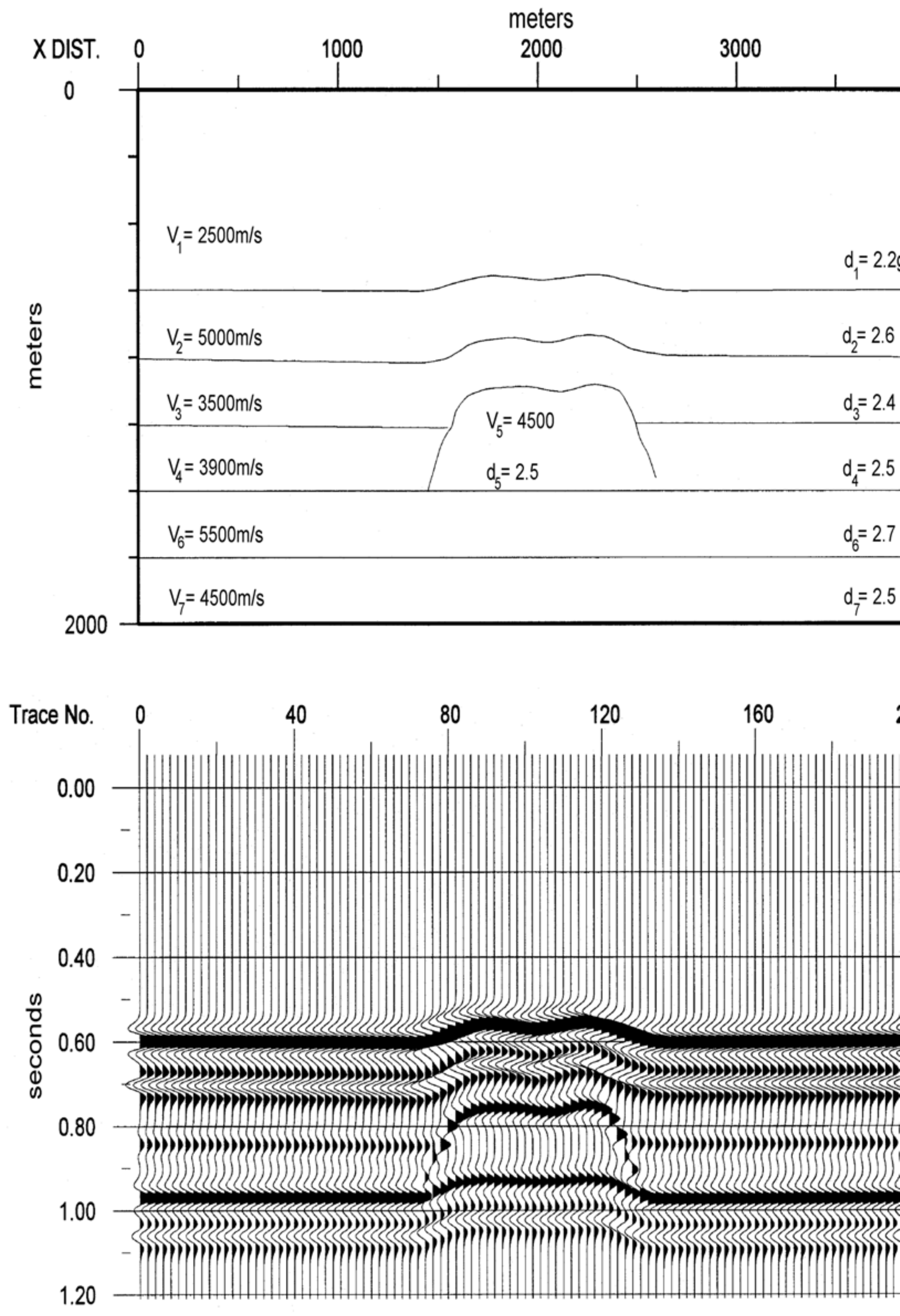


Figure 7. *Geologic model and corresponding vertical incidence synthetic seismic section. Time-structural relief along event 1/2 is due to real structural relief. Time-structural relief along event 5/6 is attributed to lateral variations the average velocity of the overlying layers. Layer 1/2 is considered to be "pulled up" beneath the modeled reef.*

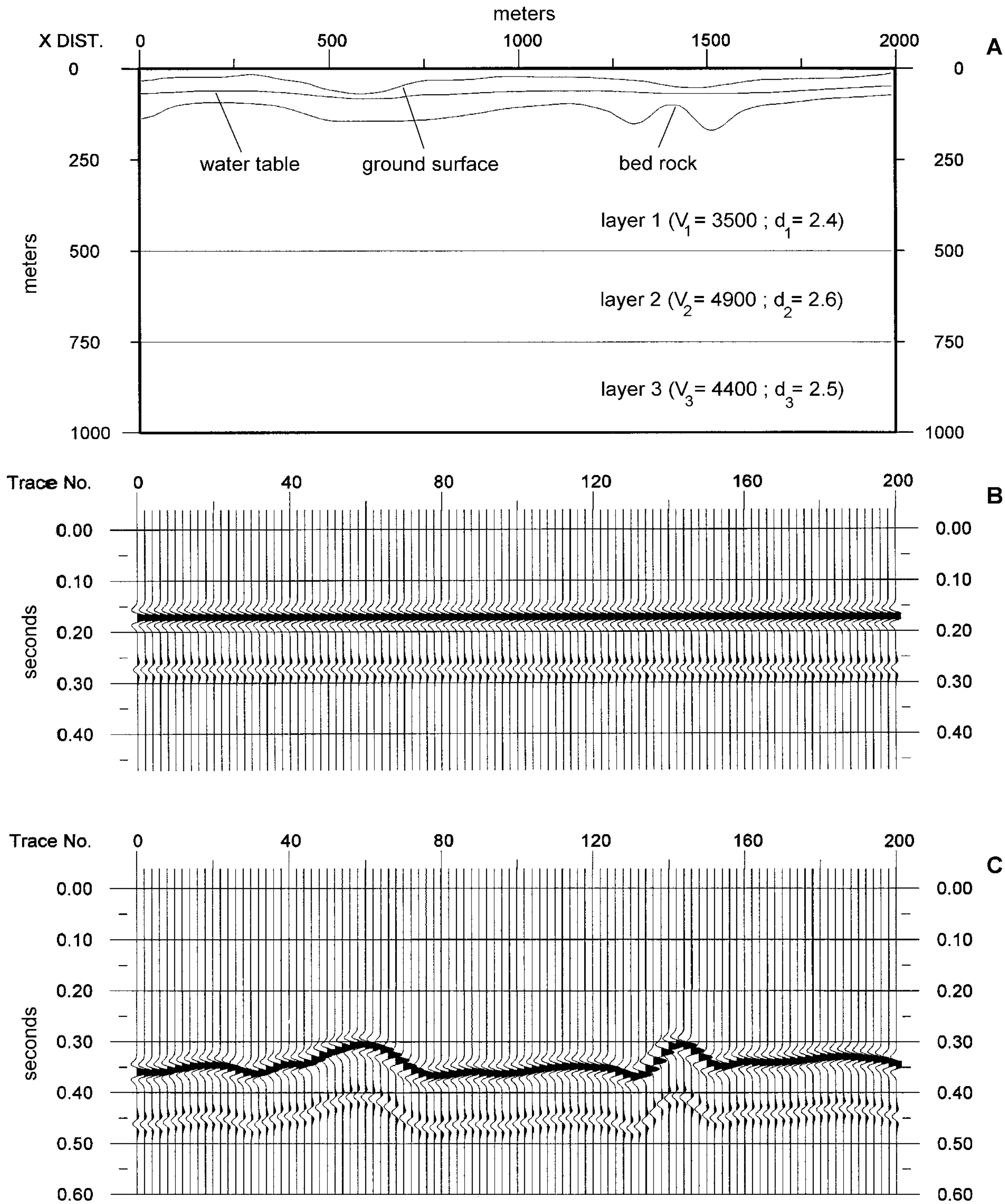


Figure 8. *Reflection seismic data are often corrected to account for variable surface topography and lateral variations in the average velocity of shallow unconsolidated strata. Elevation and weathering allow the seismic data to be displayed relative to a common (usually sub-bedrock) datum. Figure 8A is a geologic model with datum above ground surface; Figure 8B is analogous to a migrated, elevation/weathering corrected reflection seismic profile with sub-bedrock datum; the figure in Caption C is intended to represent the same reflection seismic profile without elevation/weathering corrections.*

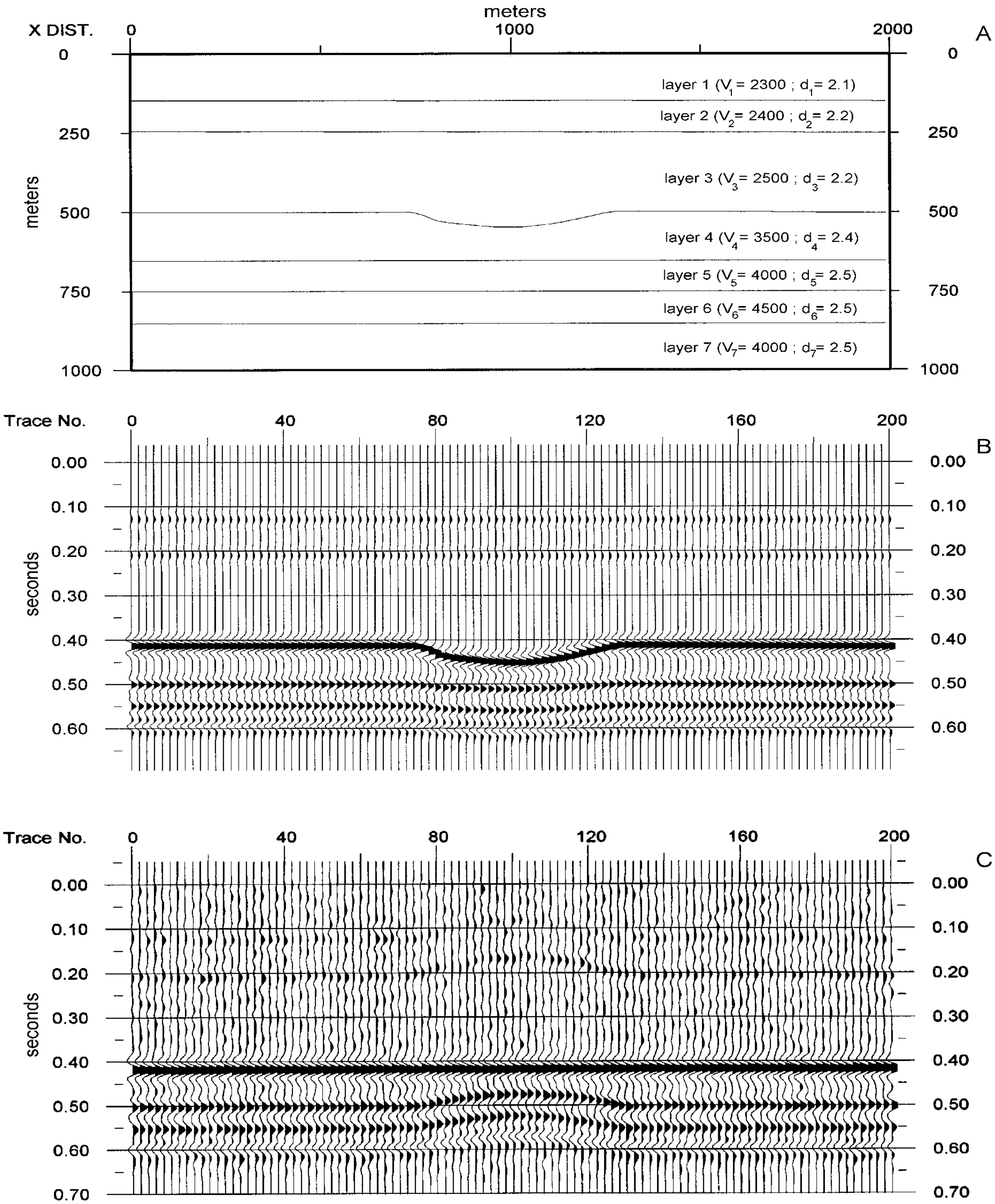


Figure 9. *Apparent time-structural relief can be an artifact of processing. The vertical incidence synthetic section (Figure 9B) represents a correctly processed reflection seismic profile. The synthetic section (Figure 9C) is intended to represent an incorrectly processed seismic profile, and illustrate a situation where a processor has used the high-amplitude reflection from unconformable surface 3/4 as an arbitrary datum (20% noise has been superimposed on the synthetic seismic section). As evidenced by the figures, injudicious processing can lead to erroneous interpretations.*

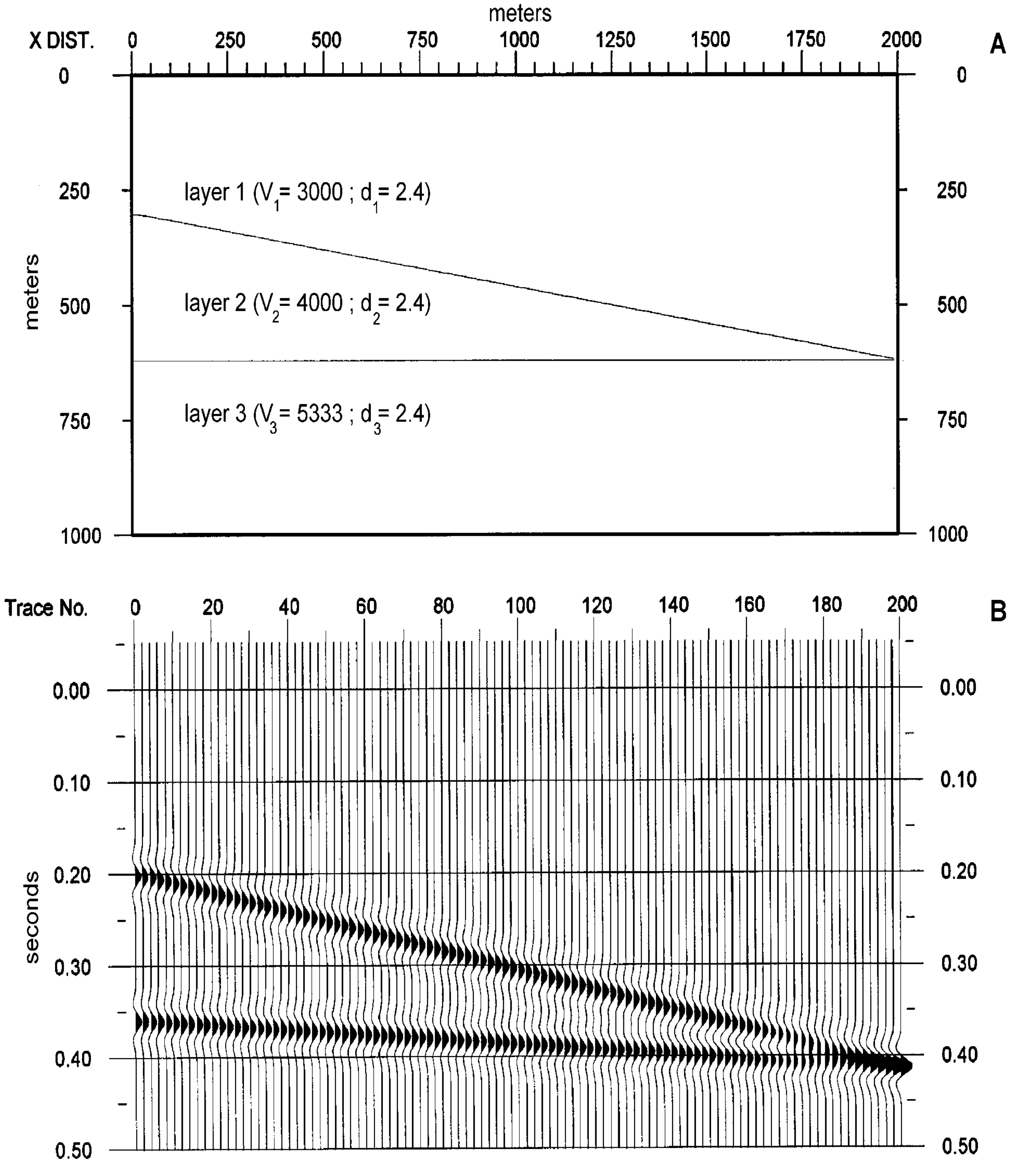


Figure 10. *Amplitude variations result from constructive of interference or "tuning" of reflected events. Figure 10A is a geologic model. Figure 10B is a vertical incidence synthetic seismic section generated using a 50 Hz normal polarity Ricker wavelet. Reflections 1/2 and 2/3 visually merge as layer 2 thins (pinches out) from left to right. At trace 150 (one-half wavelength separation on geologic section) the reflected events are distinct. At separations less than 1/4 wavelength (traces > 175), the arrival times of the events can no longer be accurately measured. At separations less than 1/8 wavelength (traces > 187), the events can no longer be visually differentiated.*

Modeling Prior to the Acquisition of Seismic Data

Seismic data are usually acquired to locate and/or delineate a known or preconceived subsurface geologic target. For example, in oil and gas exploration, the area to be surveyed has generally been selected on the basis of geological studies and is considered to be prospective with respect to the envisioned target of interest.

Forward modeling prior to acquisition can indicate of whether or not a seismic program will be able to resolve the geologic objective on processed seismic profiles (assuming good quality field data is obtained). It can verify whether a geologic target can be effectively imaged, given the limitations of the field techniques to be used. If a target is readily resolved on a synthetic seismic section, there is a reasonable probability it will also be resolved on properly acquired and processed seismic profiles.

Pre-acquisition modeling consists of transforming the envisioned subsurface geologic model (with units of depth, acoustic velocity and density) into a synthetic seismic section (in units of space, time, and reflection amplitude). Usually, if the seismic signature of a geologic target is not readily apparent on appropriately modeled synthetic seismic sections, it will not be interpretable on acquired seismic profiles. Whether modeled features will be interpretable on the acquired seismic profiles depends mostly upon the validity of the envisioned geologic model and the quality of the recorded seismic data (which is a function of cultural noise, interference from multiply reflected events, chosen acquisition parameters, quality of processing, etc.).

There are two types of pre-acquisition geologic models - structural and stratigraphic. Both are designed on the basis of well control in the immediate vicinity of the study area, regional trends, geomorphology, and the acoustic impedance characteristics of features similar to the envisioned target. The structural and stratigraphic models generally differ with respect to detail and ultimate purpose. Structural models are designed mostly to illustrate the time-structural relief component of seismic sections. In contrast, stratigraphic models are designed to provide information with respect to the character variation component of the seismic signature of the envisioned anomaly.

The structural model usually extends from the surface to a depth below the features of interest, and structural synthetic seismic sections are generated in order to determine whether the time-structural component of the seismic signature of the geologic target will be visible (Figure 14). The interpreter can use structural synthetic seismic sections to analyze the expected velocity-generated time-structural relief related to a specified subsurface geologic structure, or a suite of possible structures.

Typically, the stratigraphic model is restricted to that portion of the subsurface in the immediate vicinity of the envisioned geological anomaly. Stratigraphic synthetic seismic sections are generated in an effort to determine whether the character variation component of the seismic signature of the geological target will be seismically visible (Figures 2 and 15). The interpreter can analyze the modeled amplitude and phase variations along specific events and the expected changes in the seismic image of sequences of layers.

Based on these pre-acquisition modeling efforts, the interpreter decides whether the seismic signatures of the geological objective should be visible on output seismic profiles, assuming appropriate field acquisition parameters are employed, sufficiently good quality field data is obtained, and the data are properly processed.

Whether seismic signatures can be distinguished on field data (prior to processing) is a function of the quality, frequency and signal/noise ratio of seismic data. Subtle or weak anomalies might only be seen on the final processed section. However, likely key marker horizons are noted on the synthetic seismic section and examined on common shot records (field seismograms) as a check of data quality.

Pre-acquisition modeling can be thought of as a precautionary measure - the seismic interpreter is attempting to safeguard against acquiring seismic data in search of a target that is not likely to be visible on real seismic data, and against using inappropriate field acquisition parameters.

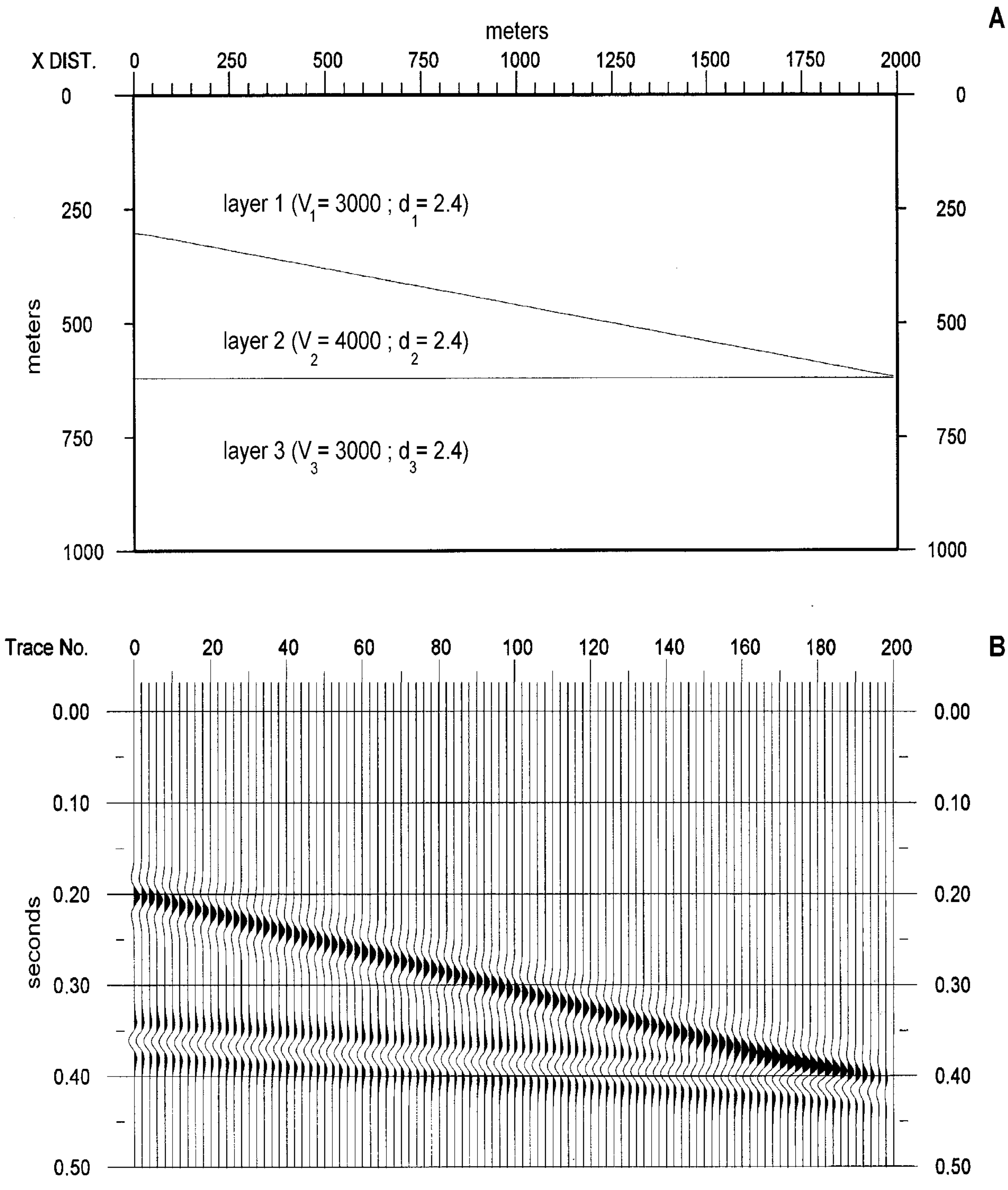


Figure 11. *Geologic model and corresponding normal polarity vertical incidence synthetic seismic section. Amplitude variations can occur as the result of destructive interference. Figure 11A is a geologic model. Figure 11B is a vertical incidence synthetic seismic section generated using a 50 Hz normal polarity Ricker wavelet. Reflections 1/2 and 2/3 visually merge as layer 2 thins (pinches out) from left to right. At trace 150 (one-half wavelength separation on geologic section) the reflected events are distinct. At separations less than 1/4 wavelength (traces > 175), the arrival times of the events can no longer be accurately measured. At separations less than 1/8 wavelength (traces > 187), the events can no longer be differentiated. At trace 200, the reflections superpose and cancel, yielding a null trace.*

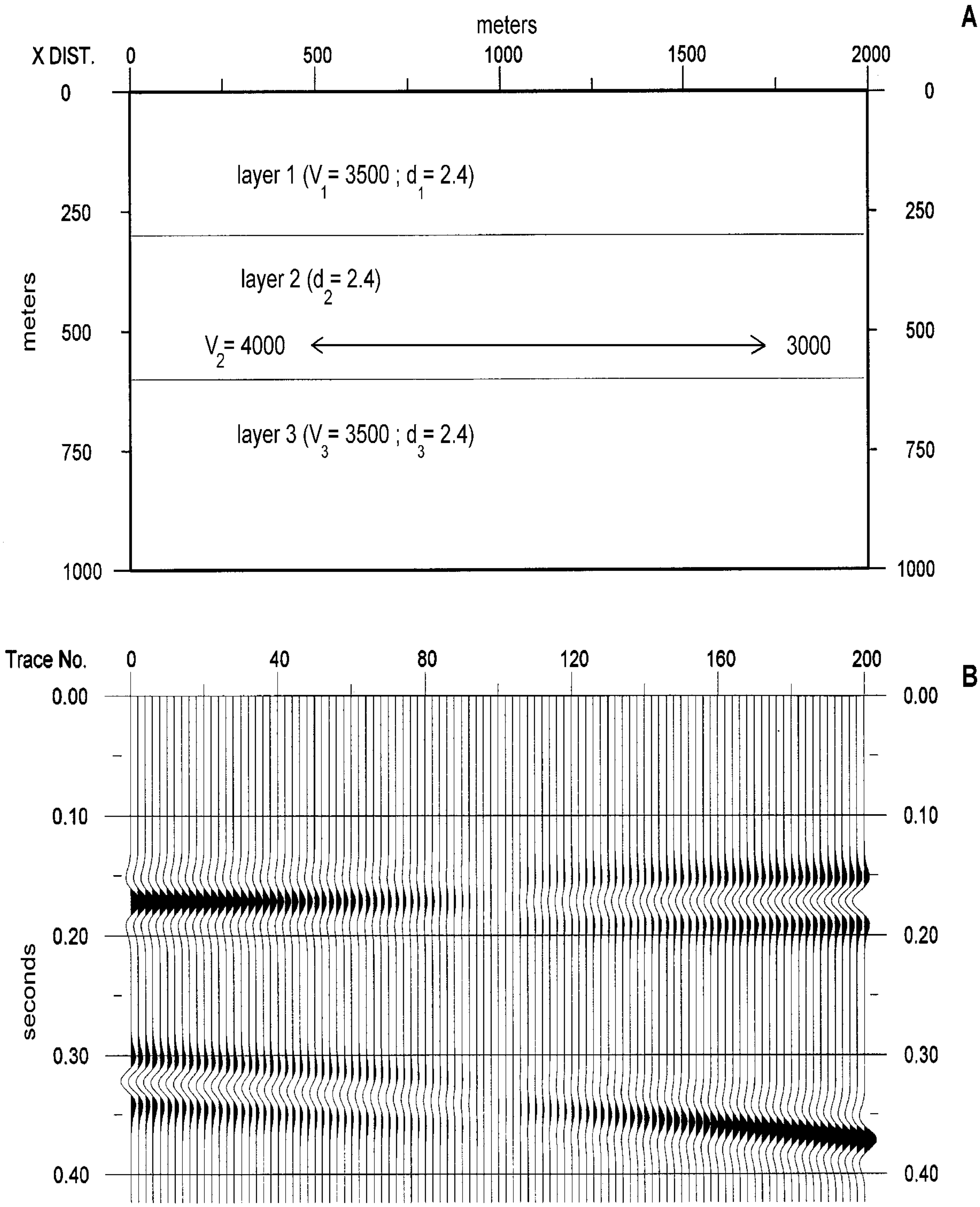


Figure 12. *Geologic model and corresponding normal polarity vertical incidence synthetic seismic section. Amplitude variations along a specific reflection can occur as the result of lateral changes in acoustic impedance contrast. In Figure 12B the amplitudes and polarities of events 2/3 and 1/2 vary from left to right as the result of a change in the acoustic velocity of layer 2.*

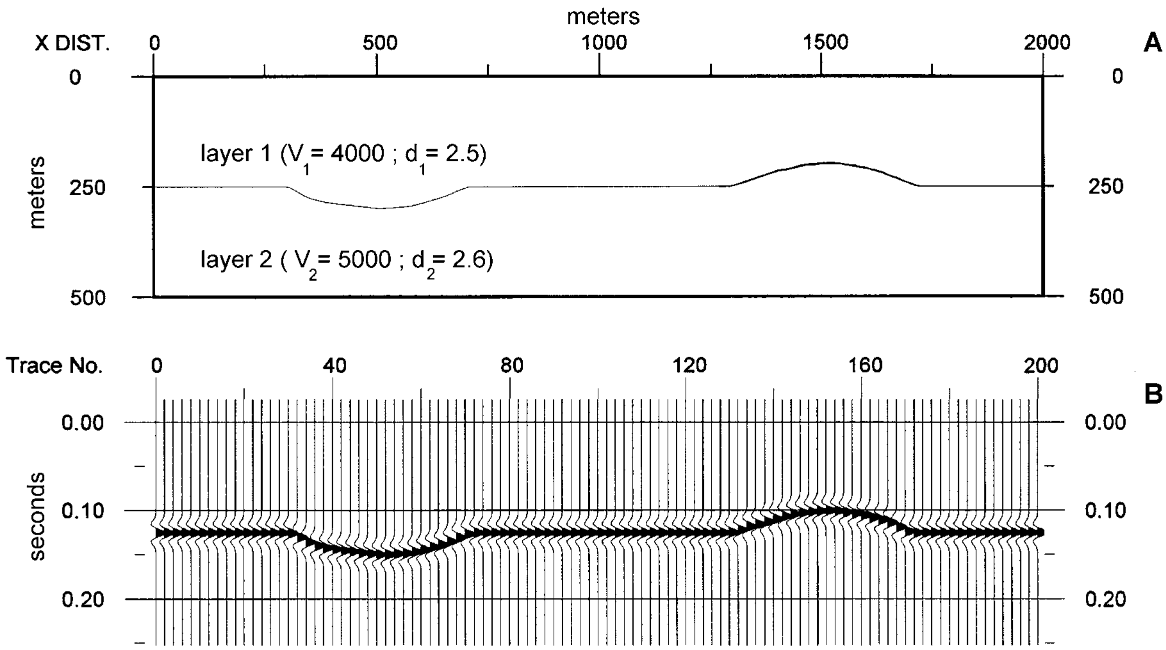


Figure 13a. *Geologic section and corresponding vertical incidence synthetic seismic section (analogous to migrated seismic profile). Ray paths are vertical. Dipping and curved surfaces are accurately located in time and space on the synthetic seismic section. Diffractions are not incorporated into synthetic section.*

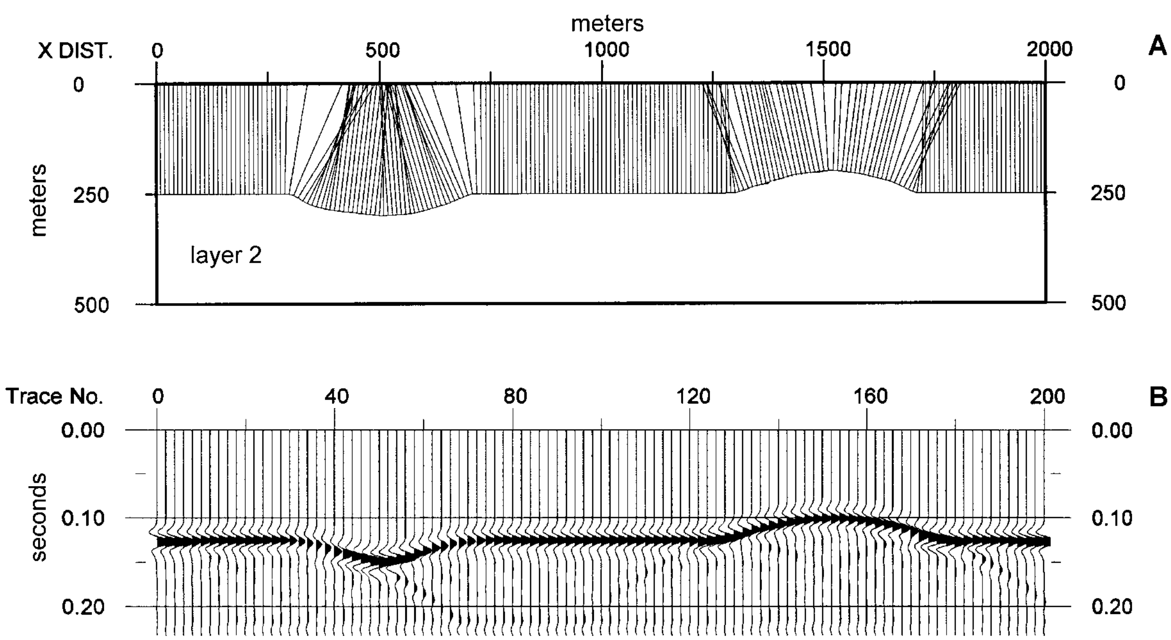


Figure 13b. *Geologic model and corresponding diffraction synthetic seismic section (analogous to non-migrated seismic data). The focal point of the syncline is below ground level. Ray paths are normally incident on reflecting horizons, and reflections originating from dipping surfaces are not placed in their correct spatial locations of origin (time and space). In a relative sense (re: Figure 13a), anticlinal structures are broadened and synclinal features are collapsed. Diffractions originating from discontinuities within the geologic model are superimposed on the reflected events. Amplitude variations result from the focusing and defocusing effects of curved and irregular surfaces.*

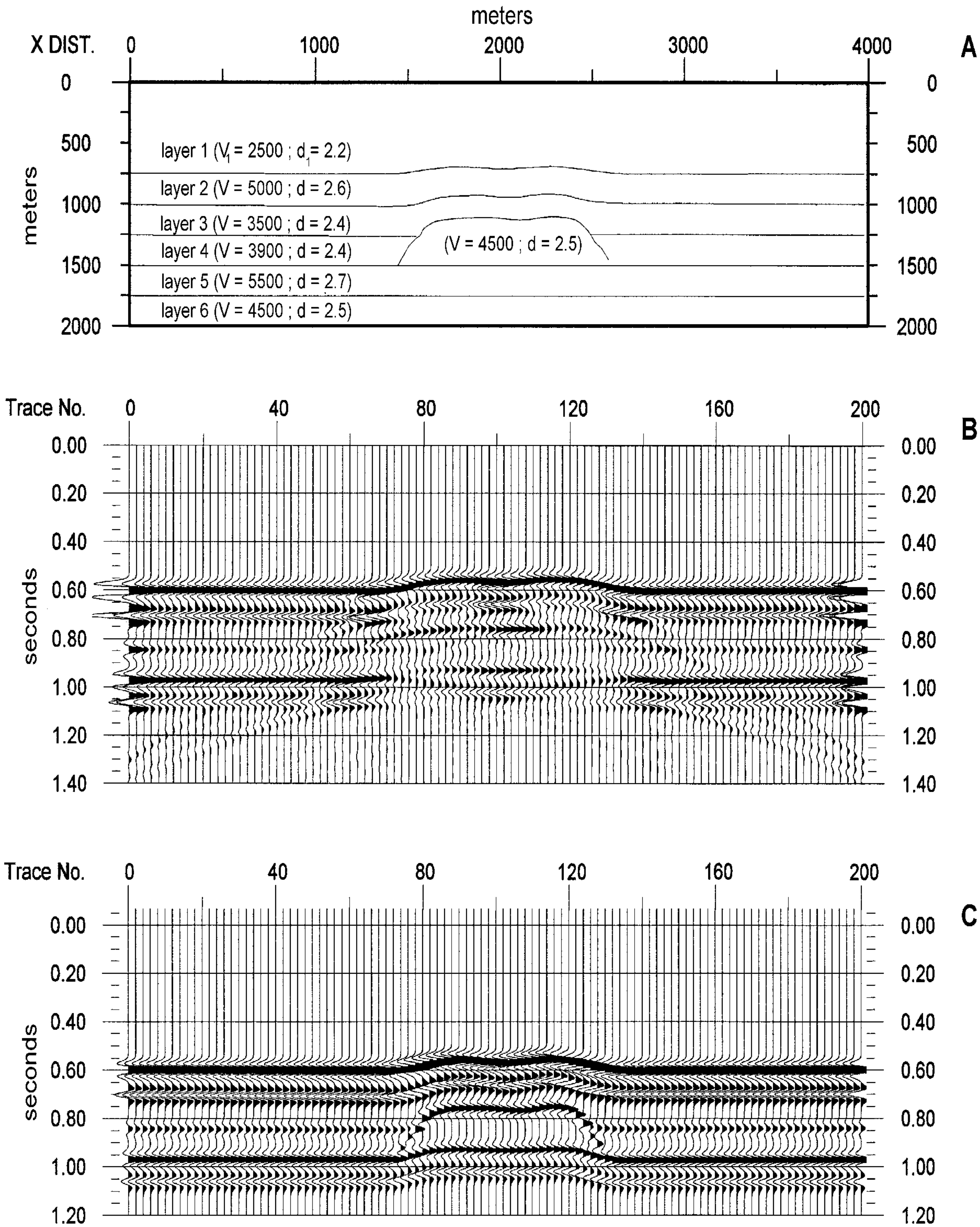


Figure 14. *Figure 14A is a geologic model. Figure 14B is a corresponding diffraction synthetic seismic section (analogous to non-migrated seismic data). The diffractions originate from discontinuities associated with the surface of the reef. Figure 14C is a corresponding vertical incidence synthetic seismic section (analogous to migrated seismic data).*

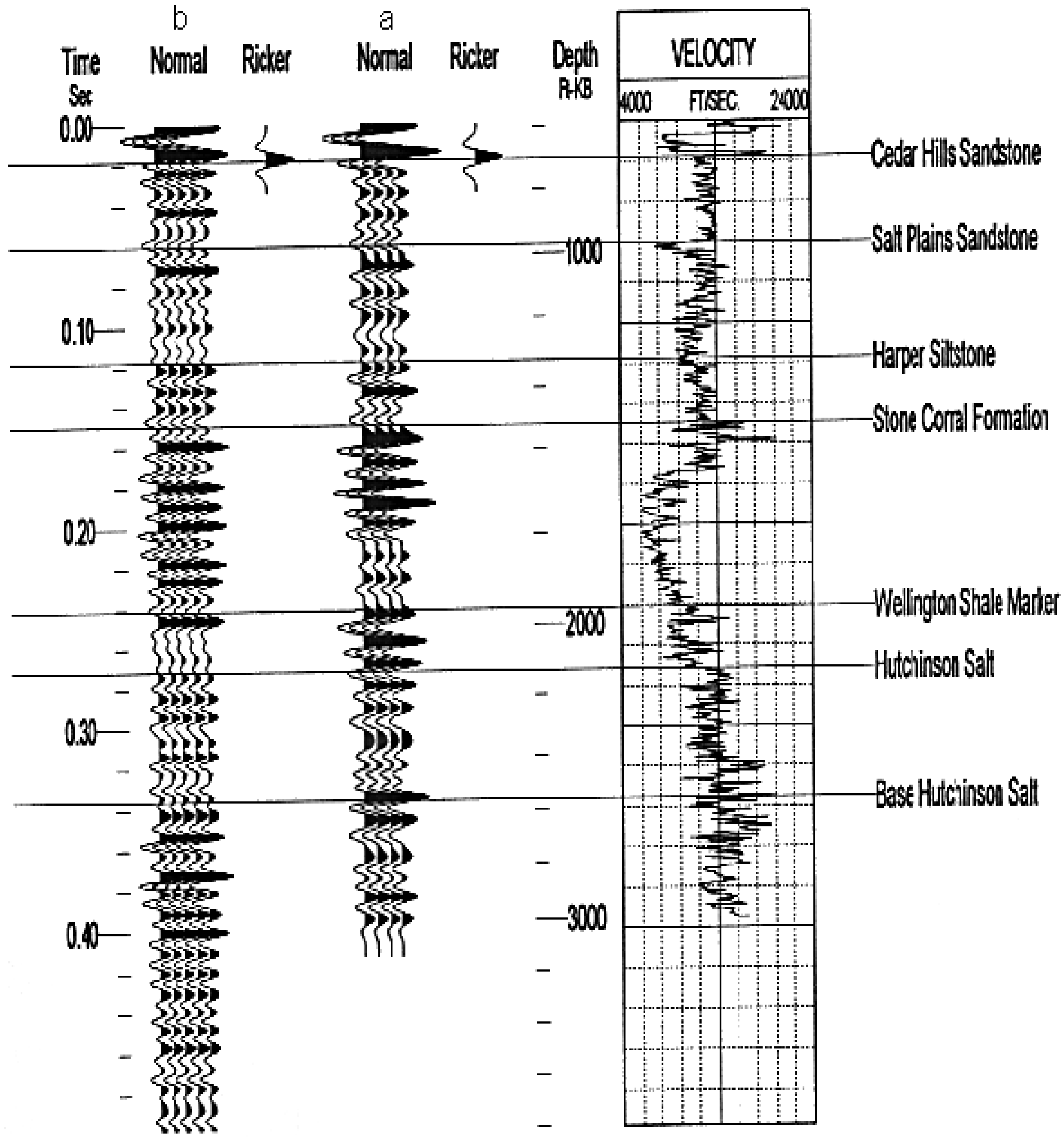


Figure 15. *One dimensional digital velocity log (linear vertical axis in time) and corresponding suite of normal polarity vertical incidence synthetic seismograms. Seismogram "**a**" consists of primary reflections only; seismogram "**b**" consists of primary reflections and all multiples. As illustrated, multiple events can mask the seismic signature (primary events only) of a geologic target and are generally considered to be noise. CDP stacking and other processing techniques are commonly used to remove and/or reduce the relative amplitudes of multiple reflections.*

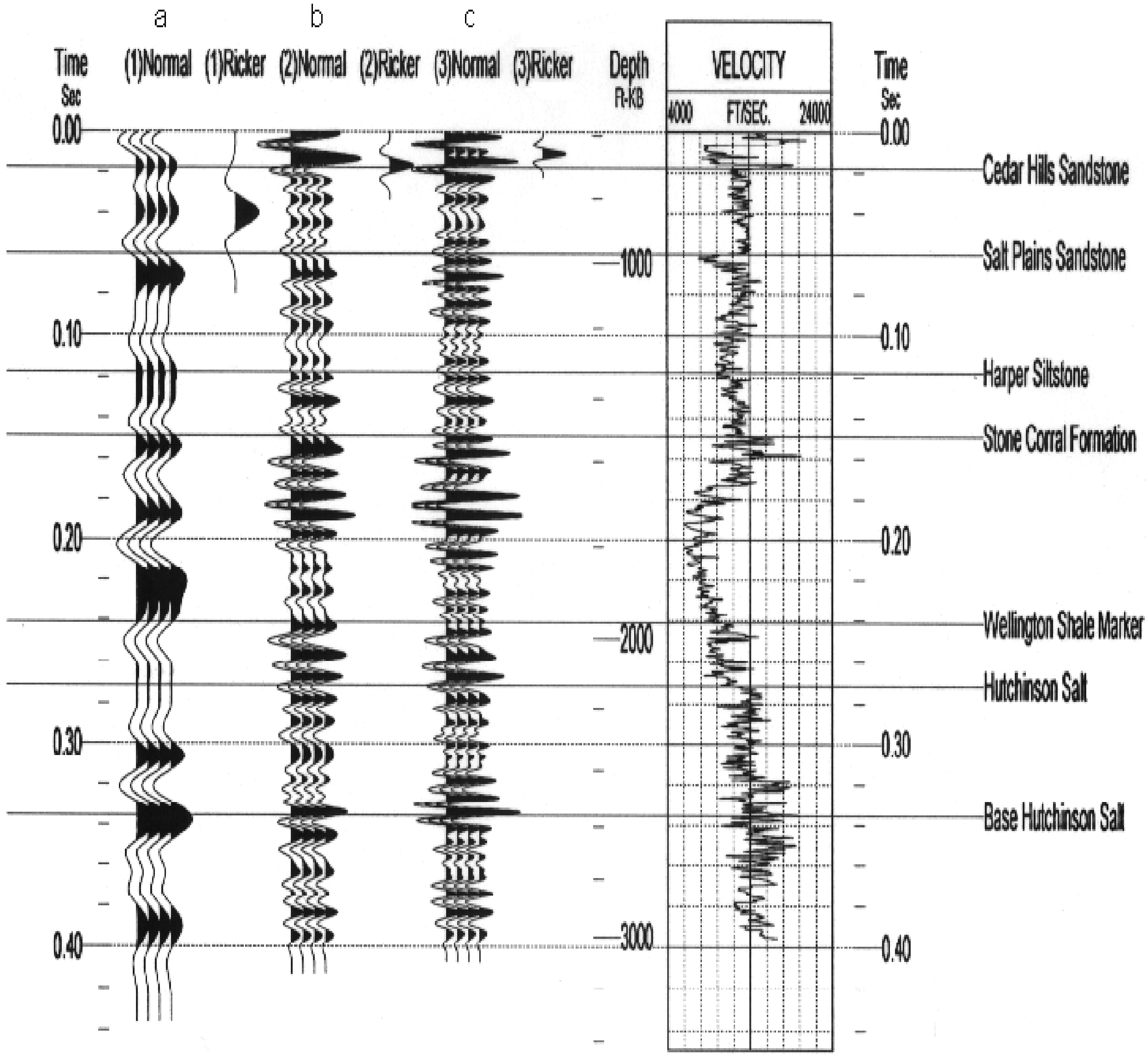


Figure 16. *One dimensional digital velocity log (linear vertical axis in time) and corresponding suite of vertical incidence synthetic seismograms: a) 25 Hz zero-phase Ricker wavelet; b) 60 Hz zero-phase Ricker wavelet; and c) 90 Hz zero-phase Ricker wavelet. As demonstrated by Figure 16, higher-frequency reflection seismic data provide for better vertical (and horizontal) resolution.*

Modeling after the Acquisition of Seismic Data

The seismic interpreter's goal is to transform (invert) processed seismic profiles into geologic models. The seismic signatures of reefs, horst blocks, abandoned mines, channel sandstones, caves, faults, salt diapers and other geologic features, must be recognized by the seismic interpreter in order to perform this qualitative/quantitative inversion. Because seismic interpretations are non-unique, the geologic model must be consistent with all available constraints. Such constraints would include acoustic and density log data, drilling and lithologic data, seismic stacking velocities, VSP control, test shot seismic velocities, etc. Experience and intuition will assist in developing and refining geologic models. The interpreter must strive for a final geologic interpretation that is consistent with appropriate geologic principles and generally accepted seismic interpretation methodologies, in addition to well log data and/or other geologic control.

During post-acquisition modeling, the seismic interpreter uses synthetic seismic sections as an interpretation aid. Typically, synthetic seismic sections are generated for all or part of a constrained initial subsurface geologic model (as envisioned). The synthetic seismic sections are compared to the real seismic data. When significant discrepancies are observed, the geologic model is modified (consistent with other independent constraints) and a new synthetic seismic section is generated. This process is repeated in an iterative manner, until the interpreter is satisfied with the correlation between the synthetic and the real reflection seismic data. Using a computer-based, statistical analysis to compare the data to the synthetic seismic section in this manner takes some of the intuitive nature out of the interpretation/inversion; however, as already mentioned, care must be taken to ensure that the final seismic interpretation is consistent with known geological constraints.

There are two complementary types of post-acquisition models - stratigraphic and structural. Both are designed on the basis of the inverted seismic data (intuitive or otherwise) and are constrained by available knowledge, well log control, check shot velocities, regional trends and morphology, and acoustic impedance characteristics of related geological features. Stratigraphical models are generated to clarify the geological origin of the character variation component of an observed seismic anomaly. Structural models are generated to determine the origin of the time-structural component of an observed anomaly.

The stratigraphic synthetic helps the interpreter analyze the amplitude and phase variation along a specific event or a specific sequence of layers in the seismic section. The accuracy of this modeling will depend on knowledge of the source wavelet of the seismic energy pulse; that is, the response to a hypothetical isolated reflector for the given seismic source used in the survey.

Using the structural synthetics, the interpreter attempts to deduce structural relief in the subsurface and to determine the lateral velocity variations that produced the observed pattern of velocity-generated time-structural relief. The accuracy of interpretations based on this modeling depends on a stable (consistent) source wavelet in the real seismic data, but is not dependent on identification of the actual form of the source wavelet as is necessary for stratigraphic seismic sections.

As an interpretational aid, post-acquisition modeling can be thought of as a precautionary measure. The interpreter is attempting to ensure that anomalous features on the seismic data do, in all probability, originate from realistic geological features of interest.

Advanced Modeling

The interpretational seismic modeling as described so far in this paper has related primarily to 1-D models of the subsurface (Figures 2 and 15) which can be varied along a profile to represent 2-D geologic models (Figures 3-12). In addition, simple acoustic ray theory and a basic convolutional model are used to produce synthetic seismic sections. The subsurface is assumed to be a sequence of horizontal layers described by their reflectivity, and the source wavelet is *convolved* (signal multiplication) with this reflectivity series to get the synthetic seismic section. This type of modeling is rapid and can be used in the field as well as in the lab as an interpretational aid. Taking into account 2-D geometric properties of rays in the subsurface (Figures 13 and 14) is only a little more difficult.

Advanced modeling techniques take into account true 3-D structure and ray paths, variable source radiation patterns, anisotropy and heterogeneity within layers, and the conversion of energy between compressional and shear waves. This advanced modeling is more computer intensive and done primarily when using synthetic seismic sections to quantitatively invert measured data for the very detailed physical property variation in the subsurface.

GPR Modeling and Interpretation

Forward modeling in support of ground penetrating radar studies can be very similar to reflection seismic modeling because the approximation for both is often the same simple 1-D acoustic ray theory, where travel times down to reflectors (described by their reflectivity) are dependent upon the (compressional or electromagnetic) velocities of the intervening layers. This is particularly evident when the radar data are vertical incidence reflection profiles similar to a stacked seismic section. The difference here is only in the subsurface geologic model. In seismic, the model consists of density and acoustic velocity variation. In GPR, the model consists of dielectric constant and electrical conductivity variation.

Since vertical and horizontal resolution is dependent upon the dominant wavelength of the reflection data, the main difference between the 1-D modeling of seismic and GPR data is related to scale. Radar velocities are on the order of the speed of light (10^9 m/s); seismic velocities are on the order of 10^3 m/s. Radar frequencies are on the order of MHz (20 to 1500); reflection seismic frequencies generally vary between 30 and 500 Hz. Thus, the wavelength (a function of velocity and frequency) for GPR data is much different (in general much smaller) than that of seismic data. Because the wavelengths are smaller for GPR data, the resolution is much greater. Lithologic units incorporated into radar models can be as thin as one millimeter (or less); lithologic units incorporated into reflection seismic models seldom have thicknesses of less than one meter.

Another modeling and interpretation concern is the notable difference between seismic and GPR geologic models: seismic velocities tend to increase with depth and radar velocities tend to decrease. Although the same ray theory describes each case, the seismic data will include critically refracted energy that has come back to the surface from subsurface interfaces, whereas GPR data may include events that have reflected from the subsurface and then have critically refracted at the surface.

Since seismic data relates to the passage of elastic waves and GPR data relates to traveling electromagnetic waves (microwave radiation), another difference between the two is the expected noise (coherent and incoherent) in each data type. This may only be a necessary consideration if the interpreter is attempting to model the noise as well as the signal (reflection signatures).

One significant difference between seismic and GPR modeling has to do with the utility of synthetics that include 2-D (or 3-D) modeling of diffractions (Figures 13 and 14). Usually, the seismic interpreter prefers to work with migrated data, which means the diffractions have been collapsed to point structural features. If any diffractions still exist within the seismic data, they are considered to be noise. In contrast, the GPR signature from a subsurface target is often characterized by prominent diffractions, and the interpreter often prefers to work with non-migrated data where the diffractions are clearly represented.

When more detailed analysis is required (e.g., for quantitative inversion analysis), the algorithm for GPR modeling necessarily becomes completely different from seismic modeling because seismic modeling must solve the physical equations for elastic waves whereas GPR modeling must solve the equations for electromagnetic waves (Maxwell’s Equations). The boundary conditions and physical properties defining these two types of waves are completely different. In addition, source radiation patterns are not the same, and coupling with other wave modes (more of a problem with elastic waves) is completely different. Thus, not only is the advanced modeling completely different for seismic versus radar waves, but even the details of simple 1-D modeling can become quite different when attempting to get more quantitative information.

Summary

Simple modeling of GPR and seismic data can be quite similar. However, fundamental differences between the two relate to the operative physical properties, resolution of geologic structure (due to subsurface velocity and source frequency differences) and some interpretational considerations. Differences in modeling algorithms become more evident when detailed, quantitative analysis is required. Nevertheless, the general methodology and utility of modeling remains the same.

There are two basic types of forward models - stratigraphic and structural. Both are designed on the basis of well control in the immediate vicinity of the study area, regional trends, and the morphology and physical property characteristics of features similar to the envisioned target. The stratigraphical and structural synthetic seismic sections generally differ with respect to detail and ultimate purpose. Stratigraphical synthetic sections are designed to provide information with respect to the character variation (horizontal) component of the reflection signature of the envisioned anomaly. Typically, stratigraphic synthetics are restricted to that portion of the subsurface in the immediate vicinity of the envisioned geological anomaly. To complement this, structural synthetic data are designed to illustrate the time-structural relief component of reflection signatures. The structural synthetic data usually extend from the surface to a depth below the features of interest.

Through forward reflection modeling, the interpreter can elucidate the potential utility of the seismic or ground penetrating radar technique prior to the acquisition of field data, and thereafter facilitate the interpretation of the acquired data. Modeling can aid the planning of an acquisition program, and it is important for interpretation, often necessary in order to make the correlation between the observed reflections and geologic interfaces.

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